Economic Dispatch

**Question 1:**

What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

**Answer to Question 1:**

Each load serving entity in the region is responsible for meeting load obligations in its service area by dispatching owned or purchased resources primarily based on the dispatch characteristics of a resource, the incremental operating cost of each resource and the short-term market price.

The investor owned utilities serving in Idaho all utilize an hourly dispatch model to stack resources and meet hourly load by dispatching resources based on the incremental cost of operation and all operational constraints. The model incorporates the characteristics of all resources available to the company including long-term purchase contracts, company owned facilities and short-term market purchases.

Non-dispatchable resources such as long-term firm contract purchases and low variable cost resources such as run of river hydro and reliable wind resources are always dispatched first to meet load. The variable cost of operating storage based hydro resources and fueled resources is then compared to short-term market prices to determine the most economical order of dispatch to meet remaining load. The utilities continually refine load forecasts to determine the most economical resource on the margin. Depending upon purchase/risk strategy and market prices, short-term purchases can be made within a year of delivery date, months ahead, day ahead or acquired in real time.

The hourly dispatch model is also used to establish the net power supply costs recovered in utility rates. The dispatch model assumes economic dispatch of company owned resources based on the incremental cost of generation and forecasted hourly market prices throughout the year under normal load and water conditions. Recovery of estimated power supply costs based on economic dispatch and annual review of actual costs incurred provides an incentive for companies to meet load as efficiently as possible.

PacifiCorp serves 1.6 million customers over 136,000 square miles in Washington, Oregon, Idaho Utah, Wyoming and California. The Company owns generating resources with a nameplate rating of 8400 Mw serving a peak load of 8922 Mw.

Idaho Power serves 440,000 customers over 24,000 square miles in eastern Oregon and Southern Idaho. The Company owns generating resources with a nameplate rating of 2912 Mw serving a peak load of 2944 Mw.

Avista Utilities serves 330,000 customers over 30,000 square miles in eastern Washington and northern Idaho. The Company owns generating resources with a nameplate rating of 1766 Mw serving a peak load of 1470 Mw

**Question 2:**

Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

**Answer to Question 2:**

The definition of Economic Dispatch as defined by the Act is appropriate. Idaho utilities utilize the most cost effective resources available within the operational constraints of the generation and transmission facilities (from a variable cost standpoint). The geographic scope of available facilities should be region wide to the extent variable costs of facility operation can be reflected in market sales/purchase prices and transmission is available for import/export to load centers.

Environmental externalities may be an additional factor to consider when dispatching resources because the cost of future environmental impacts that result from resource dispatch decisions may not be properly included in the decision making process.

**Question 3:**

How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

**Answer to Question 3:**

Because the capital cost of company owned generation is generally embedded in rates charged native load customers, only the incremental cost of operating company owned resources are considered in dispatch decisions. Utility purchases of non-utility generation through the short-term market (in lieu of operating company owned resources) may provide the non-utility generator very little recovery of capital costs. Long term contract purchases of non-utility generation by a utility are generally must run and are dispatched much like company owned resources with little or no incremental operating costs.

Idaho investor owned utilities are expected to dispatch company owned resources or purchase from the market economically to meet load in each hour of the year constrained only by operating or transmission limitations. Moreover, the company is expected to operate surplus company owned resources and sell to the market if it is economical to do so. Actual operations should not vary from the economic dispatch principle or the definition provided by the act.

Failure to economically dispatch resources could result in non-recovery of power supply costs from utility customers.

**Question 4:**

What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

**Answer to Question 4:**

Including capital costs recovery in economic dispatch decisions could result in greater dispatch of non-utility generation for those projects selling output in the short term electricity market rather than through long term firm contracts. Elimination of transmission constraints and a reduction in wheeling charges could also result in greater dispatch of non-utility generation.

**Question 5:**

If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

**Answer to Question 5:**

By definition, greater economic dispatch of non-utility resources should reduce utility and customer costs otherwise it would not occur. It may also result in construction of more non-utility owned projects. The actual impact on resource mix, energy prices and the environment would depend on the type of non-utility resources actually dispatched. At his point there are relatively few non-utility owned projects in Idaho or the region that are not under must run long-term firm sales contracts.

**Question 6:**

Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? if so, how should economic dispatch be modified or enhanced to protect reliability?

**Answer to Question 6:**

Improving conditions for economic dispatch could provide a greater variety and availability of generated resources that could improve overall reliability. A reduction in system reliability as a result of improved economic dispatch could have severe economic impacts of its own. An increase in economic dispatch that violates reliability constraints could generate benefits for one sector of the industry while increasing costs for another. Improving economic dispatch would not be warranted if the overall effect is negative.